**TECHNICAL REVIEW DOCUMENT**
**For**
**RENEWAL / MODIFICATION of OPERATING PERMIT 96OPRO132**

Public Service Company – Hayden Station
Routt County
Source ID 0010097

Prepared by Jacqueline Joyce
July and September 2007, February, June, July, September and December 2008

## I. Purpose:

This document will establish the basis for decisions made regarding the applicable requirements, emission factors, monitoring plan and compliance status of emission units covered by the renewed Operating Permit proposed for this site. The original Operating Permit was issued May 1, 2001. The expiration date for the permit was May 1, 2006. However, since a timely and complete renewal application was submitted, under Colorado Regulation No. 3, Part C, Section IV.C all of the terms and conditions of the existing permit shall not expire until the renewal Operating Permit is issued and any previously extended permit shield continues in full force and operation. This document is designed for reference during the review of the proposed permit by the EPA, the public, and other interested parties. The conclusions made in this report are based on information provided in the renewal application submitted April 1, 2005, comments on the draft permit submitted on September 23, 2008, comments received on the draft permit on November 6, 2008 during the public comment period (October 8 – November 7, 2008), previous inspection reports and various e-mail correspondence, as well as telephone conversations with the applicant. A request for a minor modification to this Operating Permit was submitted on September 13, 2007. The minor modification and renewal are being processed concurrently. Please note that copies of the Technical Review Document for the original permit and any Technical Review Documents associated with subsequent modifications of the original Operating Permit may be found in the Division files as well as on the Division website at http://www.cdphe.state.co.us/ap/Titlev.html. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this Operating Permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This Operating Permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this Operating Permit without applying for a revision to this permit or for an additional or revised construction permit.

## II. Description of Source

This source is classified as an electrical services facility under Standard Industrial Classification 4911. This facility consists of two coal fired boilers. Unit 1 is rated at 205 MW and Unit 2 is rated at 300 MW. The Unit 1 ignitors utilize either natural gas or No. 2 fuel oil and the Unit 2 ignitors utilize No. 2 fuel oil for startup, shutdown and/or flame stabilization. As part of a Consent Decree, entered by the United States District Court on August 19, 1996, Civil Action 93-B-1749, the following emission control devices were required to be installed on both Units 1 and 2: low $NO_X$ burners with over-fire air (to control $NO_X$ emissions), lime spray dryers (to control $SO_2$ emissions) and fabric filter dust collectors (to control PM emissions). The Consent Decree required that startup testing of the control devices on Unit 1 commence by December 31, 1998 and that startup testing of the control devices on Unit 2 commence by December 31, 1999. As of October 18, 1999 all control equipment required by the Consent Decree had been placed into service.

In August 1996 the Colorado Air Quality Control Commission (AQCC) adopted revisions to Colorado's Visibility State Implementation Plan (SIP), specified in a document entitled "Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part I: Hayden Station Requirements", dated August 15, 1996. The U.S. EPA approved the Visibility SIP revisions at 62 Federal Register 2305 (January 16, 1997). These revisions, concerning the Hayden Station, implemented and enforced requirements identified in the Hayden Consent Decree. Only those provisions of the Consent Decree that dealt with visibility impairment ($SO_2$ and opacity) were included in the Visibility SIP revisions.

In addition to the coal fired boilers, other significant sources of emissions at this facility include fugitive emissions from coal handling, ash handling and disposal and vehicle traffic on paved and unpaved roads. Point source emissions of particulate matter include coal crushing and conveying, an ash storage silo, two (2) ash recycle silos (recycle ash used with lime in the spray dryer), two (2) lime storage silos, two (2) ball mill slakers (prepares lime slurry for spray dryer) and two (2) recycle mixers (prepares recycle as slurry for spray dryer). Additional emission units at this facility include two (2) cooling towers.

This facility is located four miles east of Hayden at 13125 U.S. Highway 40, in Routt County. The area in which the plant operates is designated as attainment for all criteria pollutants.

Wyoming, an affected state, is within 50 miles of the plant. Flattops and Mt. Zirkel National Wilderness Areas, federal class I designated areas, are within 100 km of this facility.

The summary of emissions that was presented in the Technical Review Document (TRD) for the original permit issuance has been modified to more appropriately identify the **potential to emit (PTE)** of both criteria and hazardous air pollutants. Emissions (in tons/yr) at the facility are as follows:

| Emission Unit | PM | $PM_{10}$ | $SO_2$ | $NO_X$ | CO | VOC | Pb[1] | HAPS |
|---|---|---|---|---|---|---|---|---|
| Point Sources | | | | | | | | |
| Boiler No. 1 (Unit 1) | 257.94 | 237.30 | 1,17.73 | 3,955.05 | 194.3 | 23.32 | 0.16 | See Page 21 |
| Boiler No. 2 (Unit 2) | 356.36 | 327.85 | 1,544.21 | 4,751.42 | 268.44 | 32.21 | 0.23 | |
| Auxiliary Boiler | 1.56 | 0.78 | 56.31 | 15.64 | 3.91 | 0.16 | | |
| Ash Silo | 22.39 | 22.39 | | | | | | |
| Coal Handling System | 13.14 | 6.22 | | | | | | |
| Recycle Ash Silos | 0.09 | 0.09 | | | | | | |
| Recycle Ash Mixers | 0.16 | 0.16 | | | | | | |
| Lime Storage Silos | 0.01 | 0.01 | | | | | | |
| Ball Mill Slakers | 0.8 | 0.8 | | | | | | |
| Unit 1 Cooling Twr | 3.23 | 3.23 | | | | 1.2 | | |
| Unit 2 Cooling Twr | 5.15 | 5.15 | | | | 1.9 | | |
| **Total Point Source Emissions** | **660.83** | **603.99** | **2,718.25** | **8,722.11** | **466.65** | **58.79** | **0.39** | **32.26** |
| | | | | | | | | |
| Fugitive Emissions Sources | | | | | | | | |
| Coal Handling and Storage | 27 | 7.6 | | | | | | Negl. |
| Ash Handling and Disposal | 27.2 | 9.8 | | | | | | |
| Paved and Unpaved Roads | 406.6 | 79.8 | | | | | | |
| **Total Fugitive Emissions** | **460.8** | **97.2** | | | | | | |
| | | | | | | | | |
| **Total Emissions** | **1,121.68** | **701.19** | **2,718.25** | **8,722.11** | **466.65** | **58.79** | **0.39** | **32.26** |

[1]Lead (Pb) emissions are based on emission factors from AP-42, Section 1.1 (dated 9/98), Table 1.1-17.

**Potential to emit** used in the above table are based on the following information:

**Criteria Pollutants**

Potential to emit for the ash silo, ball mill slakers, lime storage silos, recycle ash storage silos, recycle mixers and Unit 2 cooling tower are based on permitted emissions.

Potential to emit for $NO_X$, $SO_2$ and PM from the main boilers are based on emission limitations included in the permit (SIP/Consent Decree limits for $SO_2$ and PM (0.130 lb/mmBtu and 0.03 lb/mmBtu, respectively) and Acid Rain limits for $NO_X$ (0.46 lb/mmBtu for Unit 1 and 0.40 lb/mmBtu for Unit 2)), the design heat input rate and 8760 hours per year of operation. $PM_{10}$ emissions from the main boilers are presumed to be 92% of PM emissions (per AP-42, Section 1.1 (dated 9/98), Table 1.1-6). VOC and CO emissions from the main boilers are based on AP-42 emission factors (Section 1.1, dated 9/98, Tables 1.1-3 and 1.1-19) and maximum coal consumption rate. The maximum coal consumption rate is based on the design heat input rate, the heat content of the coal from the APEN submitted on April 30, 2008 and 8760 hours per year of operation.

Potential to emit from the auxiliary boiler is based on AP-42 emission factors (Section 1.3, dated 9/98, Tables 1.3-1, 1.3-3 and 1.3-6), an assumed fuel sulfur content of 0.5 weight percent and the maximum fuel consumption rate. The maximum fuel consumption rate is based on the design heat input rate, an assumed distillate oil heat content of 140,000 Btu/gal and 8760 hours per year of operation. It should be noted that although this boiler is subject to a Reg 1 PM limitation, that limit has not been used to estimate the potential to emit of PM. Since this unit burns a clean fuel and runs infrequently, the Division considers that using the Reg 1 PM limit to estimate potential to emit is not appropriate for this unit.

Potential to emit of PM and $PM_{10}$ from the Unit 1 cooling water tower is based on the maximum water circulation rate (design rate in gallons per minute and 8760 hours per year of operation), a total solids content of 5602 ppm and 0.001 % drift using the equation included in Section II, Condition 6.3.3 of the Title V permit. Potential to emit of VOC is based on the maximum water circulation rate and the emission factor included in Section II, Condition 6.3.3 of the permit.

Potential to emit from the coal handling – point sources is based on permitted emissions (for Unit 2 equipment) multiplied by 2 to account for an additional 4 transfer points (the original Title V permit application, submitted on February 15, 1996, indicated that there were 9 transfer points, in permitting the Unit 2 equipment, 5 transfer points were identified, one was open and considered a source of fugitive emissions – doubling the Unit 2 permitted emissions accounts for the 4 transfer points not considered in permitting the Unit 2 equipment).

Potential to emit from fugitive emissions from haul roads, coal handling and ash handling are based on the estimates provided with the source's comments on the draft permit, which were submitted on September 23, 2008.

**Hazardous Air Pollutants (HAP)**

The potential to emit table on page 3 provides total HAPs for the facility. The breakdown of HAP emissions by individual HAP and emission unit is provided on page

21 of this document. HAP emissions, as shown in the table on page 21, are based on the following information:

Potential to emit of HAPS were only determined for the main boilers, the auxiliary boiler and the cooling water towers. HAPS were not estimated for the other emission units as HAPs were presumed to be negligible from these sources.

HAP emissions from the auxiliary boiler are based on AP-42 emission factors (Section 1.3, dated 9/98, Tables 1.3-9 and 1.3-11) and the maximum fuel consumption rate.

HAPS from the cooling water tower are based on permitted VOC emissions for the Unit 2 cooling water tower and calculated potential VOC emissions from the Unit 1 cooling water tower (all VOC is assumed to be chloroform).

Metal HAP emissions from the main boilers are based on AP-42 emission factors (Section 1.1, dated 9/98, Table 1.1-18) and the maximum coal consumption rate. Mercury emissions from the main boilers are based on the average projected mercury emissions that were used in the development of Colorado's Mercury Rule. HF and HCl emission from the main boilers were based on the maximum emission factor, in units of lbs/ton, determined from reported HF and HCl emissions and coal consumption on several current APENS (2007, 2006 and 2005 data) and the maximum coal consumption rate.

Note that actual emissions are typically less than potential emissions and actual emissions are shown on page 22 of this document.

Compliance Assurance Monitoring (CAM) Requirements

The source addressed the applicability of the CAM requirements in their renewal application and is discussed further in the document under Section III – Discussion of Modifications Made, under "Source Requested Modifications".

MACT Requirements

Case-by-Case MACT - 112(j) (40 CFR Part 63 Subpart B §§ 63.50 thru 63.56)

Under the federal Clean Air Act (the Act), EPA is charged with promulgating maximum achievable control technology (MACT) standards for major sources of hazardous air pollutants (HAPs) in various source categories by certain dates. Section 112(j) of the Act requires that permitting authorities develop a case-by-case MACT for any major sources of HAPs in source categories for which EPA failed to promulgate a MACT standard by May 15, 2002. These provisions are commonly referred to as the "MACT hammer".

Owners or operators that could reasonably determine that they are a major source of HAPs which includes one or more stationary sources included in the source category or subcategory for which the EPA failed to promulgate a MACT standard by the section

112(j) deadline were required to submit a Part 1 application to revise the operating permit by May 15, 2002. The source submitted a notification indicating that Hayden Station was a major source for HAPS, with equipment under the source category for industrial, commercial and institutional boilers and process heaters).

Since the EPA has signed off on final rules for all of the source categories which were not promulgated by the deadline, the case-by-case MACT provisions in 112(j) no longer apply. Note that there is a possible exception to this, as discussed later in this document (see under industrial, commercial and institutional boiler and process heaters).

### RICE MACT (40 CFR Part 63 Subpart ZZZZ)

The RICE MACT (40 CFR Part 63 Subpart ZZZZ) was signed as final on February 26, 2004 and was published in the Federal Register on June 15, 2004. An affected source under the RICE MACT is any existing, new or reconstructed stationary RICE with a site-rating of more than 500 hp.; however, only existing (commenced construction or reconstruction prior to December 19, 2002) 4-stroke rich burn (4SRB) engines with a site-rating of more than 500 hp were subject to requirements. There are three diesel fired engines that are rated at less than 500 hp that are listed in the insignificant activity list of the current permit and since all are below 500 hp they are not subject to the RICE MACT.

In addition, revisions were made to the RICE MACT to address engines $\leq$ 500 hp at major sources and all size engines at area sources. These revisions were published in the federal register on January 18, 2008. Under these revisions, existing compression ignition (CI) engines, 2-stroke lean burn (2SLB) and 4-stroke lean burn (4SLB) engines were not subject to any requirements in either Subparts A or ZZZZ (40 CFR Part 63 Subpart ZZZZ § 63.6590(b)(3)). For purposes of the MACT, for engines $\leq$ 500 hp, located at a major source, existing means commenced construction or reconstruction before June 12, 2006. The three engines included in the insignificant activity list are considered existing and are therefore not subject to the MACT. Since the source has not indicated that any additional engines have been installed at the facility, the Division considers that there are no new engines and therefore, no engines subject to the RICE MACT.

### Industrial, Commercial and Institutional Boilers and Process Heaters MACT (40 CFR Part 63 Subpart DDDDD)

The final rule for industrial, commercial and institutional boilers and process heaters was signed on February 26, 2004 and was published in the Federal Register on September 13, 2004. There are propane portable heaters included in the insignificant activity list in Appendix A of the permit. However, these units do not meet the definition of boiler or process heater specified in the rule (the definition of process heater excludes units used for comfort or space heat). Therefore the heaters included in the insignificant activity list would not be subject to the Boiler MACT requirements.

In addition, as noted in the renewal application, there is an auxiliary boiler at the facility that is not addressed in either Section II of the permit or in the insignificant activity list. The boiler is distillate oil-fired, rated at 25 mmBtu/hr and only runs when both of the coal-fired units are not running. Since the unit is a large existing liquid fuel unit and is therefore only subject to the initial notification requirements as specified in 40 CFR Part 63 Subpart DDDDD § 63.7506(b)(2). The initial notification was submitted on February 16, 2005, prior to the March 12, 2005 deadline.

As of July 30, 2007, the Boiler MACT was vacated; therefore, the provisions in 40 CFR Part 63 Subpart DDDDD are no longer in effect and enforceable. The vacatur of the Boiler MACT triggers the case-by-case MACT requirements in 112(j), referred to as the MACT hammer, since EPA failed to promulgate requirements for the industrial, commercial and institutional boilers and process heaters by the deadline. Under the 112(j) requirements (codified in 40 CFR Part 63 Subpart B §§ 63.50 through 63.56) sources are required to submit a 112(j) application by the specified deadline. As of this date, EPA has not set a deadline for submittal of 112(j) applications to address the vacatur of the Boiler MACT. Although this unit was only subject to initial notification requirements, the Division considers that a 112(j) application should be submitted for this unit. Therefore, the Division will include this emission unit in Section II of the permit and include the requirement to submit a 112(j) application by the deadline set by the Division and/or EPA.

<u>Gasoline Distribution MACTs</u>

A 6,000 gallon underground gasoline tank is included in the insignificant activity list (fuel storage and dispensing equipment in ozone attainment areas with a throughput less than 400 gal/day, averaged over 30 days are considered insignificant per Reg 3, Part C, Section II.E.3.fff). There are potential MACT standards that could apply to this operation: Gasoline Distribution (Stage I) – 40 CFR Part 63 Subpart R (final rule published in the federal register on December 14, 1994), Gasoline Dispensing Facilities – 40 CFR Part 63 Subpart CCCCCC (final rule published in the federal register on January 10, 2008) and Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities – 40 CFR Part 63 Subpart BBBBBB (final rule published in the federal register on January 10, 2008). Both of the rules published on January 10, 2008 only apply at area sources. Since this facility is a major source for HAPS, the requirements in those rules do not apply to the gasoline tank at this facility. The Gasoline Distribution (Stage I) MACT applies to bulk gasoline terminals and pipeline break-out stations. The gasoline dispensing equipment at this facility does not meet the definition of a bulk gasoline terminal or a pipeline break-out station. Therefore, none of the MACT requirements associated with gasoline distribution apply to the equipment at this facility.

<u>Federal Clean Air Mercury Rule Requirements</u>

The EPA published final rules to address mercury emissions from coal-fired electric steam generating units on March 15, 2005. These rules are referred to as the Clean Air

Mercury Rule (CAMR), which required mercury standards for new and modified emission units and provided a trading program for existing units. Under this program, sources would be required to get a permit (application due date July 10, 2008) and to meet monitoring system requirements (install and conduct certification testing) by January 1, 2009.

However, on February 8, 2008 a DC Circuit Court vacated the CAMR regulations for both new and existing units. Therefore, the federal CAMR requirements are not in effect, as of the issuance date of this renewal permit.

State Clean Air Mercury Rule Requirements

Although the Division did adopt provisions from the federal CAMR rule into our Colorado Regulation No. 6, Part A, the Division also adopted State-only mercury requirements in Colorado Regulation No. 6, Part B, Section VIII. As discussed above the provisions from the federal CAMR rule have been vacated and are no longer applicable. While the state-only mercury requirements rely in some part of the federal CAMR rule (primarily for monitoring and reporting requirements), there are emission limitation and permit requirements that do not rely on the federal rule and are still in effect.

To that end, as an existing mercury budget unit each of these units are required to comply with either of the following standards on a 12-month rolling average basis beginning January 1, 2014 (Colorado Regulation No. 6, Part B, Section VIII.C.1.b):

0.0174 lb/GWh OR 80 percent capture of inlet mercury

These units would be subject to more stringent mercury standards beginning January 1, 2018 as set forth in Colorado Regulation No. 6, Part B, Section VIII.C.1.c.

It should be noted that if either Units 1 or 2 qualify as a low emitter (actual mercury emissions of no more than 29 lbs/yr), the mercury standards indicated above do not apply.

Since the mercury limitations do not apply until 2014 and the permit application is not due until 18 months prior to commencing construction on the mercury control equipment (Colorado Regulation No. 6, Part B, Section VIII.D.2) the renewal permit does not include the state-only mercury requirements.

Regional Haze Requirements

The two coal-fired units at this facility are subject to the regional haze requirements for best available retrofit technology (BART) and as such a BART analysis was conducted and a permit has been issued to address the BART requirements. The BART requirements have been included in Colorado Construction Permit 07RO0113B, which was issued September 12, 2008.

Although the BART permit includes emission limitations for PM, $SO_2$ (30-day and 90-day rolling averages) and $NO_X$, only the $NO_X$ emission limitations are new. The PM and $SO_2$ limitations that were included in the BART permit are the same limitations included in the current Title V permit, which were based on a Consent Decree, which was ultimately rolled into Colorado's SIP (Long-Term Strategy Review and Revision of Colorado's State Implement Plan for Class I Visibility Protection Part I: Hayden Station Requirements (8/15/96), as approved by EPA at 62 FR 2305 (1/16/97)).

The BART permit specifies that PSCo shall demonstrate compliance with the $NO_X$ unit-specific emission limits no later than 180 days after initial startup of the $NO_X$ control equipment for each unit or as expeditiously as practicable within five years following EPA approval of the state implementation plan for regional haze that incorporates these BART requirements, whichever is earlier. The BART permit also requires that an application be submitted to modify the Title V permit to incorporate the BART requirements within 12 months after the startup of the $NO_X$ control equipment for the last unit. Since startup of the $NO_X$ control equipment is set for some time in the future and the application to modify the Title V permit to include the BART requirements is not due until twelve months after installation of the $NO_X$ controls for the last unit, the renewal permit does not include the provisions from the BART permit (07RO0113B).

It should be noted that the BART construction permit requires that the source submit BART progress reports with their Title V semi-annual reports. This report shall include: 1) the installation date (expected or actual) for the BART controls, if any; 2) the anticipated date on which the source will achieve the BART emission limits set forth in this permit (07RO0113B); 3) a description of progress made since the prior BART Progress Report toward the installation of BART controls, if relevant, and toward achieving the BART emission limits set forth in this permit (07RO0113B).

## III. Discussion of Modifications Made

**<u>Source Requested Modifications</u>**

### April 1, 2005 Renewal Application

The source requested the following changes in their April 1, 2005 renewal application.

<u>Section II, Conditions 5.1 and 5.2</u>

The source has requested a lower limit on the quantity of materials processed through the recycle ash silos in order to keep potential pre-control emissions below the major source level. The source has requested that the throughput limits be reduced from 556,000 tons/yr to 296,000 tons/yr and the emission limits for PM and $PM_{10}$ be dropped from 0.17 tons/yr to 0.09 tons/yr. In addition, the source has requested that the throughput limits for the recycle mixers be reduced from 556,000 tons/yr to 296,00 tons/yr and the PM and $PM_{10}$ emission limits dropped from 0.3 tons/yr to 0.16 tons/yr to reflect the throughput changes made to the recycle ash silos. The changes have been made as requested.

Appendix A – List of Insignificant Activities

Auxiliary Boiler

The source indicated that they had a distillate oil-fired auxiliary boiler on site that is used to supply auxiliary steam and steam heat to the plant and runs only when both main coal-fired boilers are down for maintenance. The source indicated that although the boiler is rated at 25 mmBtu/hr, actual, uncontrolled emissions are less than 2 tons/yr, therefore the boiler is exempt from APEN reporting requirements and can be considered an insignificant activity and requested that the boiler be included in the insignificant activity list.

The source also indicated that although the facility is a major source for HAPS and the requirements in 40 CFR Part 63 Subpart DDDDD, "National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters" apply. Since the unit is an existing large liquid fuel unit, it is only subject to the initial notification requirements in accordance with 40 CFR Part 63 Subpart DDDDD § 63.7506(b)(2). The initial notification was submitted on February 16, 2005.

Under the "catch-all" language in Colorado Regulation No. 3, emission units cannot take an exemption from APEN reporting requirements, minor source construction permit requirements and/or be considered insignificant activities for Title V permitting purposes if they are subject to MACT requirements. Although this unit was only subject to the initial notification requirements in the Boiler MACT, as discussed previously in this document under Section II – Source Description, the Boiler MACT was vacated and the provisions in 40 CFR Part 63 Subpart DDDD are not longer in effect and enforceable, consequently a 112(j) application is required for this unit. Therefore, the boiler will be included in Section II of the permit.

In addition, it should also be noted under the "catch-all" language in Colorado Regulation No. 3, emission units cannot take an exemption from APEN reporting requirements, minor source construction permit requirements and/or be considered insignificant activities for Title V permitting purposes, if the potential to emit, taking in account the full design rate and continuous operations triggers PSD review requirements.

Based on AP-42 emission factors (Section 1.3 (dated 9/98), Table 1.3-1 (for boilers < 100 mmBtu/hr) and table 1.3-3) and assuming a fuel heating value of 140,000 Btu/gal, emissions from the boiler are below the PSD significance level for all pollutants except $SO_2$. $SO_2$ emissions were calculated at 56.3 tons/yr based on a fuel sulfur content of 0.5 weight percent (note that at a sulfur content of less than 0.36 weight percent, emissions are below 40 tons/yr). To that end, since the facility is a major stationary source for purposes of PSD review, the Division must evaluate whether this auxiliary boiler triggered PSD review requirements.

According to information provided by the source, the auxiliary boiler at the facility commenced startup October 31, 1974 (note that this auxiliary boiler replaced one that had been installed in 1968). The first PSD rules were published as final on December 5, 1974 and applied to PM and $SO_2$ emissions at certain listed sources, including fossil fuel fired steam electric plants of more than 1000 mmBtu/hr. However, these rules only applied to sources that commenced construction on or after June 1, 1975. Therefore, the auxiliary boiler did not trigger any PSD review requirements.

Other Equipment

In their September 23, 2008 comments on the draft permit the source requested the following revisions to the insignificant activity list:

- Revised the description under Reg 3, Part C.II.E.3.b to indicate three (3) 6,500 gallon 12.5% sodium hydroxide tanks.
- Added a 330 gallon sodium hydroxide tank under Reg 3, Part C.II.E.3.n
- Removed the evaporation ponds from Reg 3, Part C.II.E.3.oo, since they have been removed from service
- Added two transformer oil storage tanks under Reg 3, Part C.II.E.3.aaa
- Added a forklift refueling tank under Reg 3, Part C.II.E.3.ccc
- Added a diesel fuel tank (coal handling # 1) under Reg 3, Part C.II.E.3.fff

Compliance Assurance Monitoring (CAM) Assessment

The CAM requirements apply to any emission unit that uses a control device to meet an emission limitation or standard and has pre-controlled emissions above the major source level. There are several emission points at the facility that could potentially be subject to the CAM requirements. The source provided information regarding the applicability of the CAM requirements to the emission units at the facility as discussed below.

**Emission sources with no emission limitations**

The source identified the following activities as units with no emission limitations and therefore not subject to the CAM requirements: portions of the coal handling system (conveying system from unloading to pile (includes both crushers) and the conveying system from pile to Unit 1), Unit 1 cooling tower, and fugitive emissions from coal handling and storage, ash handling and disposal and traffic on paved and unpaved roads. The Division agrees, that since these emission sources do not have any emissions limitations, the CAM requirements do not apply.

## Emission sources with emission limitations

The remaining sources have emission limitations and would therefore be subject to the CAM requirements if they used a control device to meet that emission limitation and have pre-control emissions above the major source level.

### Pre-control emissions below the major source level

The source identified the following emission sources as having pre-control emissions below the major source level and therefore not subject to the CAM requirements: the ash silo, remaining portions of the coal handling system (conveying from the pile to Unit 2), the recycle ash silos, recycle mixers, lime storage silos, ball mill slakers and the unit 2 cooling water tower. The Division agrees that the coal handling system, the lime storage silos, ball mill slakers and the recycle ash mixers have uncontrolled emissions below the major source level and therefore are not subject to CAM. The Divisions agrees that with the requested change in throughput limits for the recycle ash silos, that those emission units also have uncontrolled emissions below the major source level and therefore are not subject to CAM. The other sources warrant further review and are discussed below.

Unit 2 cooling water tower – the cooling water tower is equipped with drift eliminators which reduce drift to 0.001%. Without the drift eliminators, uncontrolled PM and $PM_{10}$ emissions from the cooling water tower would exceed the major source level. However, the Division considers that the drift eliminators are not considered a control device. In 40 CFR Part 64, § 64.1, control device means "equipment other than inherent process equipment that is used to destroy or remove pollutants prior to discharge to the atmosphere…For purposes of this part, a control device does not include passive control measures, that act to prevent pollutants from forming, such as the use of seals, lids or roofs to prevent the release of pollutants". The Division considers that the drift eliminators are considered inherent process equipment and are passive devices and as such are not considered control equipment. Therefore, the Division considers that the CAM requirements do not apply to the Unit 2 cooling water tower.

Ash Silo – there are essentially two separate activities conducted at the ash silo, loading and unloading. Separate emission factors are used for each activity and the source considers that each activity should be considered separately. Emissions from silo loading are controlled by a baghouse and uncontrolled emissions from this activity are below the major source level. When ash is unloaded from the baghouse, the ash is blended with water in a pug mill located at the base of a silo and then released down a chute to an open truck. The source considers that the unloading process is inherent to the process, because mixing water with the ash is necessary to make it possible to handle during the unloading, transport and disposal of the ash. While the Division is not necessarily convinced that the unloading process (mixing ash with water) is inherent process equipment, we do not think that it meets the definition of control equipment. The preamble to the CAM rule provides more insight into the control technology definition and provides the following (from October 22, 1997 federal register, page 54912, 3rd column, under *control devices criterion*)

> The final rule provides a definition of "control device" that reflects the focus of Part 64 on those types of control devices that are usually considered as "add-on" controls." This definition does not encompass all conceivable control approaches but rather those types of control devices that may be prone to upset and malfunction, and that are most likely to benefit from monitoring of critical parameters to assure that they continue to function properly. In addition, a regulatory obligation to monitor control devices is appropriate because these devices generally are not a part of the source's process and may not be watched as closely as devices that have a direct bearing on the efficiency or productivity of the source.

The Division considers that for the unloading process the operation of the pug mill to mix the ash with water is not considered an add-on control device and is not the type of device that would benefit from monitoring critical parameters. Therefore, the Division agrees that based on the specific provisions in the CAM requirements that unloading ash from the silo is an uncontrolled activity. Therefore, the Division considers that the CAM requirements do not apply to the ash silo unloading operations.

**Pre-control emissions above the major source level**

The source identified both boilers as having pre-control emissions above the major source level. The boilers are both subject to PM, $SO_2$ and $NO_X$ emission limitations. Controlled emissions of these pollutants exceed the major source level and these units use emission controls (baghouse for PM, lime spray dryer for $SO_2$ and low $NO_X$ burners and over-fire air for $NO_X$) to meet their emission limitations. Therefore, the boilers are potentially subject to the CAM requirements.

The boilers are subject to $SO_2$ and $NO_X$ emission limitations under the Acid Rain Program (Section III of the current permit). Pursuant to 40 CFR Part 64 § 64.2(b)(1)(iii), the CAM requirements do not apply to Acid Rain Program emission limitations.

Both boilers are subject to several $SO_2$ emission limitations and Unit 2 is subject to a 3-hour $NO_X$ limitation. The current Title V permit requires that the source use continuous emission monitoring systems to demonstrate compliance with the $SO_2$ and $NO_X$ emission limitations. Therefore, since the Title V permit specifies a continuous compliance method for these emission limitations, the CAM requirements do not apply in accordance with the provisions in 40 CFR Part 64 § 64.2(b)(1)(iv).

CAM does apply to the boilers with respect to the PM emission limitations. Note that although the units are both subject to opacity limits, they are not emission limitations subject to CAM requirements. The source submitted a CAM plan with their renewal application. In their CAM plan, the source proposed visible emissions, pressure differential and preventative maintenance as indicators. For visible emissions, excursions are identified as an opacity value exceeding 15% for more than 10 seconds and any long term increase in opacity of 10% above baseline levels for normal operation. For pressure differential, an excursion is defined as an increase in differential pressure of 3 inches of water column or greater from normal baseline levels accompanied by a sustained increase in opacity over 10%.

The Division has reviewed the CAM plan submitted and while we accept the plan in part, we consider that changes to the plan are necessary. The Division considers that the following changes are necessary to the plan.

Visible Emissions

The Division accepts the indicator range of 15% opacity for more than 10 seconds and will include this in the permit. In their September 23, 2008 comments on the draft permit, the source requested that the 15% opacity indicator be revised to specify the duration as 60 seconds, rather than 10 seconds. The Division has revised this indicator as requested.

The second indicator range of “a long term increase in opacity emissions from baseline conditions during normal operations to opacity emissions greater than 10% over an extended period of time” is non-specific as to the time frame and it is not clear that the 10% opacity represents an acceptable opacity level as an indicator range. Therefore, the Division will include as CAM, the compliance provisions required for new (constructed after February 28, 2005) electric utility steam generating units subject to PM fuel based emission limitations (i.e. units of lb/mmBtu) in 40 CFR Part 60 Subpart Da, since such monitoring represents presumptively acceptable monitoring in accordance with the provisions in 40 CFR Part 64 § 64.4(b)(1)(4). The compliance provisions required by Subpart Da requires that a baseline opacity level be set during a performance test and then requires monitoring on a 24-hour average. If the opacity 24-hour average exceeds the baseline level, then the source must investigate and take the appropriate corrective action. Note that as provided for in 40 CFR Part 60 Subpart Da § 60.48Da(o)(2)(iv), periods of startup, shutdown and malfunction may be excluded from the 24-hour average.

The baseline opacity level determined under the provisions of NSPS Subpart Da specify that 2.5% opacity be added to the average opacity determined during the performance test, although the baseline opacity level can be no lower than 5% opacity. In their September 23, 2008 comments on the draft permit, the source indicated that they considered the 2.5% addition to the opacity determined during the performance test to be overly stringent, since the units required to conduct this monitoring under NSPS Subpart Da are subject to more stringent particulate matter limitations. The Division agreed with the source in part and has revised the opacity add-on based on the results of the performance test. However, in no case would the baseline opacity be set lower than 5%.

Pressure Differential

The source has indicated that an excursion would be “an increase in differential pressure across a baghouse of 3 inches of water column or greater from the unit’s normal specific operating load during normal operating conditions, as well as a sustained increase in opacity greater than 10%”.  While the proposed language does not specifically define the pressure differential for the “unit’s normal specific operating load”, in their justification the source indicates that the normal pressure differential varies based on the operating load.  While the Division understands that it may be difficult to identify specific ranges since the appropriate pressure differential varies depending on the load, failure to identify the specific range makes it difficult for the Division to independently determine whether an excursion has occurred.  In addition, as indicated in the source’s September 23, 2008 comments on the draft permit, an increase or decrease in the pressure differential from the normal level at a specific operating load is not necessarily considered an indicator of decreased baghouse performance by itself.  However, an increase or decrease in the pressure differential from the normal level, accompanied by a sustained increase in opacity is an indication of potential baghouse problems.

Since the normal pressure differential is specific to load and cannot be easily defined and because pressure differential by itself is not necessarily an indicator of potential problems with the baghouse, the Division will not include pressure differential in the CAM plan as an indicator.  In accordance with 40 CFR Part 64 § 64.4(b)(4), presumptive CAM is monitoring included for standards that are exempt from CAM (i.e. NSPS standards promulgated after November 15, 1990) to the extent that such monitoring is applicable to the performance of the control device (and associated capture system).  As discussed previously, the Division has revised the source’s CAM plan to require that visible emissions be monitored in accordance with the monitoring required for new boilers subject to 40 CFR Part 60 Subpart Da.  The emission limitations and monitoring for new boilers were published as final in the February 27, 2006 federal register, although changes to the monitoring requirements were published as final in the federal register on June 13, 2007.  New boilers subject to the revised PM emissions limits in 40 CFR Part 60 Subpart Da are required to monitor compliance with the PM emission limitation using their COM by establishing a baseline opacity.  Therefore, the baseline opacity monitoring that the Division is including in the CAM plan represents presumptive CAM and the Division does not believe that it is necessary to include pressure differential as an additional indicator.

It should be noted that new sources subject to the NSPS Da PM limitation are also required to conduct annual performance tests.  While the Division has not included annual performance testing in the permit as part of the CAM plan, the Division does require performance tests as periodic monitoring to demonstrate compliance with the PM limitations.  Frequency of testing is annual, unless the results of the testing are much lower than the standard, then less frequent testing is allowed.

Preventative Maintenance

The Division accepts PSCo's proposal for semi-annual internal baghouse inspections and will include this in the permit.

In general, the CAM plan has been included in Appendix G of the permit as submitted, except that the corrections indicated above have been made to the plan and some language has been omitted, revised or relocated in order to streamline the plan.

**September 13, 2007 Minor Modification**

In their modification request received on September 13, 2007, the source requested that the permit be revised to increase the VOC emission limit from the Unit 1 cooling water tower from 1.8 tons/yr to 1.9 tons/yr.  In their application, the source indicated that this modification met the requirements for a minor permit modification and requested that the minor permit modification procedures in Colorado Regulation No. 3, Part C, Section X be used.

Colorado Regulation No. 3, Part C, Section X.A identifies those modifications that can be processed under the minor permit modification procedures.  Specifically minor permit modification "are not otherwise required by the Division to be processed as a significant modification" (Colorado Regulation No. 3, Part C, Section X.A.6).  The Division requires that "any change that causes a significant increase in emissions" be processed as a significant modification" (Colorado Regulation No. 3, Part C, Section I.A.7.a).  The increase in permitted (potential) emissions associated with this modification is 0.1 ton/yr which is below the PSD significance level of 40 tons/yr.  Therefore, the Division aggress that this modification qualifies as a minor modification.

No modeling was required for this modification.  In general accurate and cost effective methods for modeling ozone impacts from stationary sources are not available. Therefore, individual source ozone modeling is not routinely requested for construction permits.

<u>Section II, Condition 6.3</u>

The VOC emission limit for the Unit 2 cooling water tower was increased from 1.8 tons/yr to 1.9 tons/yr as requested.

**<u>Other Modifications</u>**

In addition to the modifications requested by the source, the Division has included changes to make the permit more consistent with recently issued permits, include comments made by EPA on other Operating Permits, as well as correct errors or omissions identified during inspections and/or discrepancies identified during review of this renewal.

The Division has made the following revisions, based on recent internal permit processing decisions and EPA comments, to the Hayden Station Operating Permit with the source's requested modifications. These changes are as follows:

Section I - General Activities and Summary

- Added a column to the Table in Condition 5.1 for the startup date of the equipment.

Section II.1 – Boilers, Coal-Fired

- Removed the note in Condition 1.1.2 that says no further testing is required during this permit term

- Revised the language in Condition 1.1.2 to specify that the performance tests shall be used to set the baseline opacity for the CAM plan and specified how the baseline opacity shall be determined.

- Revised the language in Condition 1.2 to specify that the emission factor used shall be the emission factor determined from the most recent performance test. This change is needed since currently the source is calculating emissions based on the results of the 1999 performance test.

- Revised the table column "Monitoring – Interval" for Condition 1.17 by replacing "quarterly" with "annually"

- Added the CAM language as "new" Condition 1.18.

Section II.3 – Particulate Matter Emissions – Fugitive Sources

- In the summary tables, the permit condition numbers listed for the Missile 3B – coal unloaded (first table) and ash disposed (second table) were corrected.

Section II.4 – Particulate Matter Emissions – Ash and Coal Handling

- In their September 23, 2008 comments on the draft permit, the source indicated that the Division should indicate either in the permit or the technical review document that a control efficiency of 90% is applied to emission calculations for the crushers since they are enclosed. Therefore, the Division added language in Condition 4.2.1 to indicate that a control efficiency of 90% could be applied to the emission calculations for the crusher.

Section II.9 – Catastrophic Failure (for Purposes of $SO_2$ Emissions)

- Added "malfunction" in parentheses after the word "upsets" in Condition 9.2.

Section II.11 – Particulate Matter Emission Periodic Monitoring Requirements

- Removed the language in Condition 11.1 regarding the COMS and opacity spikes. The Division considers that with the CAM plan requirements this language is no longer necessary.

- Revised the stack testing language in Condition 11.3 to clarify the frequency of testing. The language in the permit addresses testing within the expected five-year permit term. The permit terms may be extended, provided a timely and complete renewal application has been submitted. For the most part, complete and timely renewal applications have been submitted and the term of the permits have been extended beyond the originally anticipated five-year permit term. Therefore, the language has been revised to set specific deadlines for testing, which more appropriately reflects the Division's intent to require testing for particulate matter at a minimum of every five years. To that end, the language regarding waiving testing within the last two years of the permit term, in the event that annual testing was triggered, has been removed. In general, the results of the initial tests have not been above 75% of the standard and annual testing has not been triggered. Therefore, the Division considers that the language is not necessary.

Section II.12 – Continuous Emission Monitoring System Requirements

- Some formatting changes were made which affect the numbering of conditions under Condition 12.3.

- Removed the phrase "and the traceability protocols of Appendix H" from Condition 12.3.2, since Appendix H of the current version of 40 CFR Part 75 is "reserved". Note that Condition 12.3.1 specifies that the continuous emission monitoring systems are subject to the requirements of 40 CFR Part 75 and that would include any applicable appendices, regardless of whether or not they are specifically called out in this condition.

- Inserted the phrase "as specified in" between "Part 75" and "Condition 12.3.3.2" in Condition 12.3.4.6.

- Based on citizen comments received on November 6, 2008 during the public comment period, the following sentence was added after Condition 12.4.5 (98% COMS availability): "Note that compliance with the 98% availability requirement is not a shield against enforcement with respect to the continuous emission monitoring system requirements in 40 CFR Part 75."

- Based on citizen comments received on November 6, 2008 during the public comment period, Condition 12.4.6 (monitoring opacity when the COM is down) was removed from the permit.

- Replaced the phrase “concerning upset conditions and breakdowns” with “concerning affirmative defense provisions for excess emissions during malfunctions” in Condition 12.5.5 to reflect revisions made to the Division’s Common Provisions Regulation.

<u>“New” Section II.16 – Auxiliary Boiler</u>

As discussed previously in this document, although this boiler has actual uncontrolled emissions below the APEN de minimis level, since a case-by-case 112(j) MACT application will be required for this emission unit, it must be included in Section II of the permit. Although this unit is being included because of the case-by-case 112(j) MACT application, the Division considers that it is appropriate to include all applicable requirements for this unit, which include the following:

- APEN reporting requirement - in the event that emissions from this unit exceed the de minimis level. The permit will include a requirement to record annual fuel consumption and calculate emissions annually to determine whether submittal of an APEN is required.

  The permit will include emission factors from AP-42, Section 1.3, dated September 1998, Tables 1.3-1 (for boilers < 100 mmBtu/hr burning distillate fuel), 1.3-3 (for industrial boilers burning distillate fuel) and 1.3-6. The emission factors that will be included in the permit are shown in the table below:

| Pollutant | Emission Factor ($lb/10^3$ gallon) |
|---|---|
| PM | 2 |
| $PM_{10}$ | 1 |
| $SO_2$ | 144S |
| $NO_X$ | 20 |
| CO | 5 |
| VOC | 0.2 |

S = weight percent sulfur

- Reg 1 opacity requirements in Section II.A.1 and 4 (20% / 30%)

  The permit will require that the source conduct method 9 readings annually in order to monitor compliance with the opacity standards. The 30% opacity requirement applies during certain specific conditions, if the duration of the specific condition is less than one hour, then a method 9 is not required for the 30% opacity standard.

- Reg 1 particulate matter requirements in Section III.A.1.b ($PE = 0.5 \times (FI)^{-0.26}$, where PE = PM limit in lbs/mmBtu and FI = fuel input rate in mmBtu/hr).

  Based on the heat input rate the calculated PM emission limit is 0.216 lb/mmBtu. Based on calculation using the AP-42 emission factor, use of No. 2 fuel oil ensures compliance with the PM limit provided the heat input of the No. 2 fuel is no less than 9,260 Btu/gal.

- Reg 1 $SO_2$ requirements in Section VI.A.3.b.(i) (1.5 lb/mmBtu)

  Based on calculation using the AP-42 emission factor and assuming a fuel sulfur content of 0.5 weight percent, use of No. 2 fuel ensures compliance with the PM limit provided the heat input of the No. 2 fuel is no less than 48,000 Btu/gal.

<u>Section III – Acid Rain Requirements</u>

- Revised the table to include calendar years corresponding to the relevant permit term for the renewal.

- Minor changes were made to the standard requirements, based on changes made to 40 CFR Part 72 § 72.9.

- Removed the requirement in Section 4 to submit a copy of any revised certificate of representation to the Division. Submitting a copy of the certificate of representation to the permitting authority is not required under the regulations.

<u>Appendices</u>

- Added the auxiliary boiler to the tables in Appendices B and C.

## PSCo Hayden Total HAP Emissions

| Unit | HCl | HF | Mercury | Metals | Formaldehyde | Hexane | chloroform | BTEX | Naphthalene | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Boiler 1 (Unit 1) | 1.13 | 6.82 | 2.86E-02 | 5.34 | | | | | | 13.31 |
| Boiler 2 (Unit 2) | 1.56 | 6.82 | 1.40E-02 | 7.38 | | | | | | 15.77 |
| Auxiliary Boiler | | | | 4.54E-02 | 2.58E-02 | | | 5.02E-03 | 8.84E-04 | 0.08 |
| Unit 1 Cooling Tower | | | | | | | 1.20 | | | 1.20 |
| Unit 2 Cooling Tower | | | | | | | 1.90 | | | 1.90 |
| | | | | | | | | | | |
| Total | 2.68 | 13.64 | 4.26E-02 | 12.76 | 2.58E-02 | 0.00 | 3.10 | 5.02E-03 | 8.84E-04 | 32.26 |

HAP emissions from cooling tower based on all VOC equal chloroform emissions.

**PSCo Hayden Actual Emissions (tons/yr)**

| Unit | PM | $PM_{10}$ | $SO_2$ | $NO_X$ | CO | VOC | HAPS |
|---|---|---|---|---|---|---|---|
| Boiler 1 (Unit 1) | 101.1 | 93 | 1248.4 | 4081.5 | 188.9 | 22.6 | 5.9 |
| Boiler 2 (Unit 2) | 118.9 | 109.3 | 1470 | 3692 | 246.9 | 29.6 | 7.82 |
| Aux. Blr* | | | | | | | |
| Coal - fugitive | 23.45 | 6.17 | | | | | |
| Coal - pt source | 3.99 | 1.32 | | | | | |
| Ash - fugitive | 6.8 | 2.5 | | | | | |
| Ash - pt source (silo) | 12 | 12 | | | | | |
| Haul Roads - fug | 297.5 | 58.3 | | | | | |
| Ball mill slakers | 0.584 | 0.584 | | | | | |
| Lime storage silos | 0.005 | 0.005 | | | | | |
| Recycle ash silos | 0.009 | 0.009 | | | | | |
| Recycle Mixers | 0.016 | 0.016 | | | | | |
| Unit 1 Cooling Twr** | 6.5 | 6.5 | | | | 2.8 | |
| Unit 2 Cooling Twr** | | | | | | | |
| | | | | | | | |
| Total | 570.85 | 289.70 | 2,718.40 | 7,773.50 | 435.80 | 55.00 | 13.72 |
| Total - Fugitive | 327.75 | 66.97 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Total - Point source | 243.10 | 222.73 | 2,718.40 | 7,773.50 | 435.80 | 55.00 | 13.72 |

*Emissions below APEN de minimis

**Emissions are for both cooling towers together

Actual emissions from Boilers 1 and 2, lime storage silos, recycle ash silos,recycle mixers and ball mill slakers from APEN submitted 4/30/08 (2007 data)

Actual emissions coal handling based on APEN submitted 4/19/07 (2006 data)

Actual emissions from haul roads and cooling towers from APEN submitted 4/19/05 (2004 data)

Actual emissions from ash handling based on APEN submitted April 27, 2004 (2003 data)

HAP emissions from Units 1 and 2 consist of HCl, HF and selenium